MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills 26R Storage Project

Injection Zone Monitoring Well 328-25R

Facility Information

Facility Name: Elk Hills 26R Storage Project
328-25R

Facility Contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CP Details_328-25R	1	12/28/22	Original document, combines well construction, operating procedures, and plugging plan into monitoring well narrative document.

Introduction

CTV requires four monitoring wells for the Elk Hills 26R Storage Project. CTV intends to repurpose three existing wells for monitoring the injection interval and one existing well for above zone monitoring. Figure 1 identifies the wells proposed for the project. This document describes the construction, logging, testing, and plugging plans for injection zone monitoring well 328-25R.

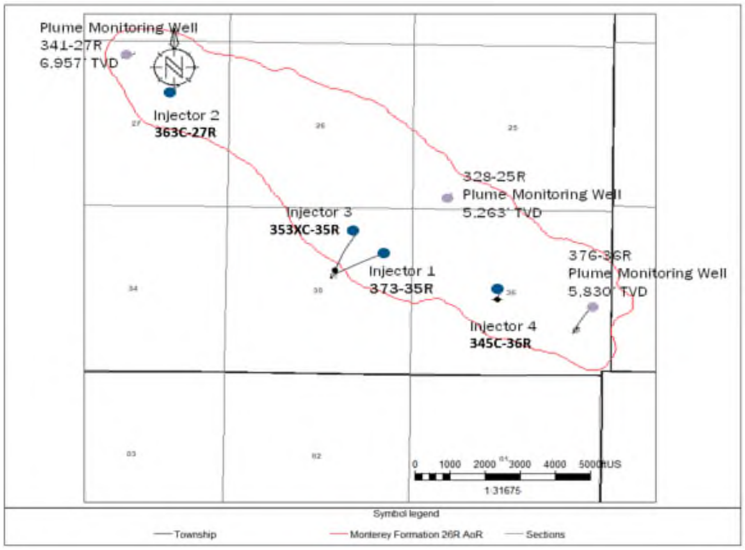


Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 328-25R is an existing oil and gas production well that was drilled in 1979 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be reused for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct and evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

<u>Construction Details [40 CFR 146.82(a)(12)]</u>

Injectate Migration Prevention

328-25R was drilled in 1979, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors.
2. Although no USDW is present, multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing.
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement, and each casing string was cemented to surface.
4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the injection zone and consistent with cementing operations results. Cement is present above the top of the injection zone (~5,220 feet MD) in

the CBL logging interval within the Monterey formation and across the Reef Ridge formation (from base of 7" casing to ~4,376 feet MD).

5. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted.
6. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
7. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous injection conditions.
8. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.

Materials

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

- Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Packer – corrosion resistant alloy material or coating and hardened rubber elastomer element material.
- Casing – the standard K-55 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
- Cement- portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Injection and Confining Zones.

Standards

Well materials follow the following standards:

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing

4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Casing

The Monterey Formation temperature in 26R is approximately 210 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the reservoir conditions associated with maintaining annular fluid and pressure. The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

Table 1: Casing Specifications for the 328-25R monitor

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)
Conductor	20' - 60'	24	20	19.124	94	-	-	2.62	-
Surface	20' - 318'	17.5	13.375	12.715	48	H-40	Short	2.62	1730
Intermediate	20' - 3002'	12.25	9.625	8.835	40	K-55	Long	2.62	3950
Long-String	12' - 80' 80' - 5112' 5112' - 6542'	8.75	7	6.276 6.366 6.276	26 23 26	K-55	Long	2.62	4980 4360 4980

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

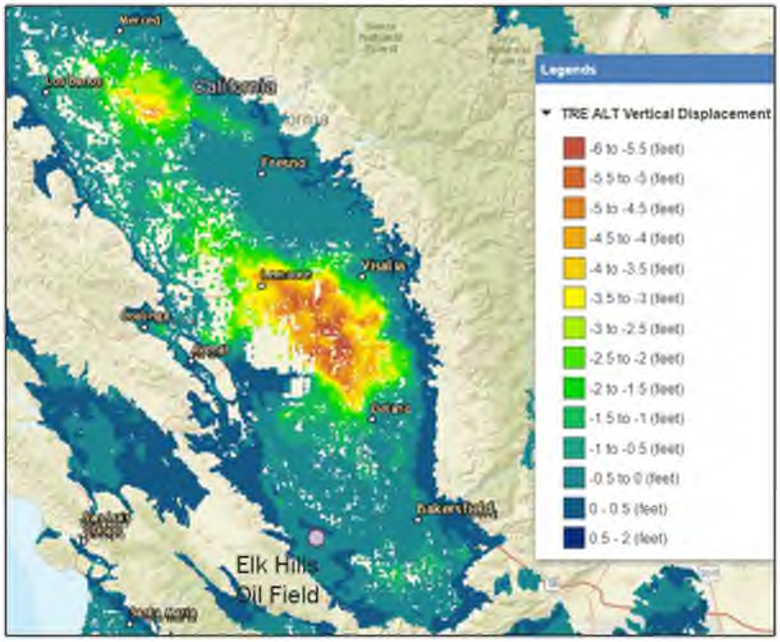


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class G portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8" casing string was cemented with Class G portland cement with returns to surface. The 9-5/8" casing string was primary cemented with Class G portland cement followed by a cement top job for cement coverage to surface. The 7" casing string was cemented in place with Class G portland cement for cement coverage above the 9-5/8" shoe to 1450' MD. Subsequently, a CBL was run from 6498' – 0' and indicates annular isolation throughout and above the Monterey and Reef Ridge formations (TOC@1,450').

Tubing and Packer

The information in the tables provided in Table 2 and Table 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications may be modified prior to conversion during pre-operational testing.

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Tubing	5228'	2.875	2.441	6.5	L-80 CRA	Premium	10,570	11,170

Table 3 provides specifications of a sealbore packer suitable to be used in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the long-string casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	5198'	30.2	23 - 32	5.687	3.25

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.366	6.049

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7” casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The wellhead tree will include redundant master valves and wing valves, and the valves will remain closed during normal injection operations. Safety valves or other automatic shut-off devices are not required for monitoring wells, in general. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided in the following discussion. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
328-25R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 7" casing to surface

Deviation Survey

Deviation checks were acquired during drilling at varying frequency and a deviation survey was acquired after drilling by a high resolution continuous dipmeter from 2989' feet measured depth (MD) to bottom hole at 6,675 feet MD (see Table 5).

Table 5: Extract of Deviation Survey for the well 328-25R.

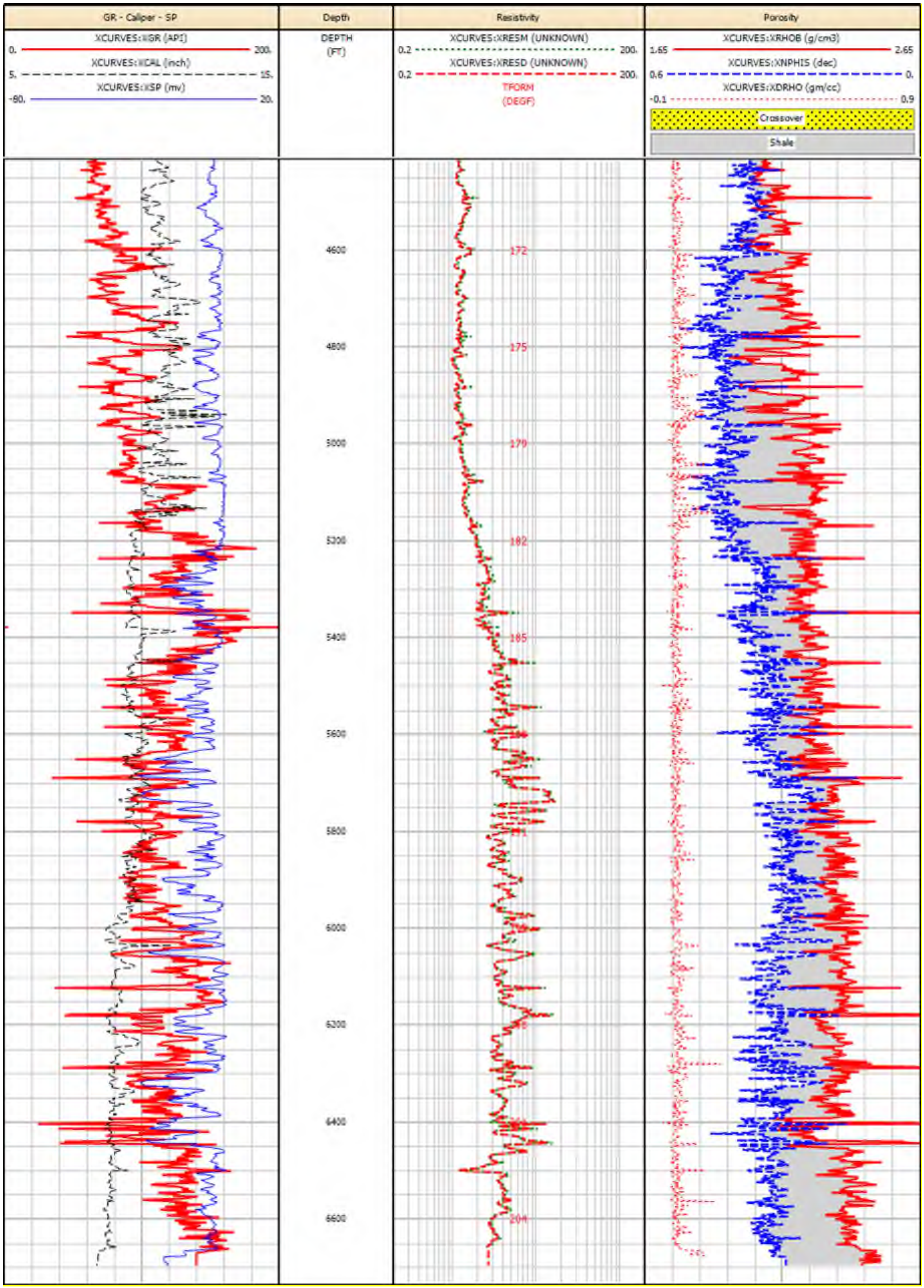
MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		4,813.30	3.25	54.88	4,811.20
2989.3	0.66	252.1	2989.2		4,934.90	2.99	49.06	4,932.60
3050.1	0.61	311.1	3050		4,995.70	2.99	46.19	4,993.30
3,110.90	0.39	319.9	3,110.80		5,056.50	3.04	46.19	5,054.00
3,171.70	0.33	331.3	3,171.60		5,117.30	3.03	36.16	5,114.80
3,232.50	0.47	348.6	3,232.40		5,178.10	2.83	43.34	5,175.50
3,293.30	0.73	338.5	3,293.20		5,238.90	3.23	47.67	5,236.20
3,354.10	0.85	351.5	3,354.00		5,299.70	4.14	36.25	5,296.90
3,414.90	0.75	348.6	3,414.80		5,360.50	4.36	34.75	5,357.50
3,475.70	0.63	351.5	3,475.60		5,421.30	4.71	30.38	5,418.10
3,536.50	0.51	347.2	3,536.40		5,482.10	5.04	36.13	5,478.70
3,597.30	0.57	4.5	3,597.20		5,542.90	5.19	31.88	5,539.20
3,658.10	0.64	6	3,658.00		5,603.70	5.02	31.75	5,599.80

3,718.90	0.61	13.2	3,718.80		5,664.50	4.66	36.13	5,660.40
3,779.70	0.68	10.2	3,779.60		5,725.30	4.09	40.5	5,721.00
3,840.50	0.67	11.7	3,840.40		5,786.10	4.16	42	5,781.60
3,901.30	1.02	17.25	3,901.20		5,846.90	3.72	40.38	5,842.30
3,962.10	1.63	31.75	3,962.00		5,907.70	3.45	37.5	5,903.00
4,022.90	2.36	43.25	4,022.70		5,968.50	3.47	31.75	5,963.70
4,083.70	3.07	49	4,083.50		6,029.30	3.81	30.38	6,024.30
4,144.50	3.79	57.75	4,144.10		6,090.10	3.96	30.38	6,085.00
4,205.30	4.3	67.97	4,204.80		6,150.90	4.2	30.38	6,145.70
4,266.10	4.72	53.41	4,265.40		6,211.70	4.23	37.63	6,206.30
4,326.90	4.75	52	4,326.00		6,272.50	4.45	27.5	6,266.90
4,387.70	4.55	56.31	4,386.60		6,333.30	4.43	33.25	6,327.50
4,448.50	4.34	54.88	4,447.20		6,394.10	4.75	31.88	6,388.10
4,509.30	4.13	59.25	4,507.80		6,454.90	5.02	31.75	6,448.70
4,570.10	4.07	62.03	4,568.50		6,515.70	5.77	34.75	6,509.20
4,630.90	3.9	59.19	4,629.10		6,576.50	6.25	36.25	6,569.70
4,691.70	3.7	66.38	4,689.80		6,637.30	6.79	29	6,630.10
4,752.50	3.49	63.44	4,750.50		6,675.00	6.96	39	6,667.60

Open Hole Log Analysis

Open-hole wireline log data was acquired prior to installation of 7" casing long string. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (middle), neutron porosity and bulk density in track 3 (right most).

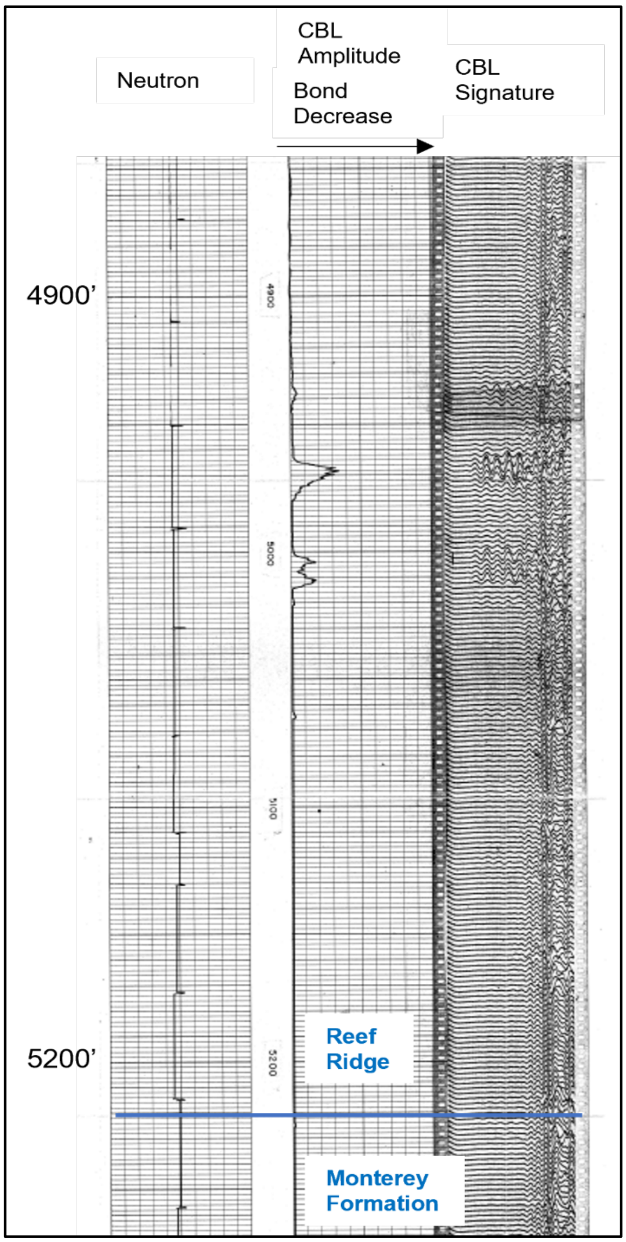
Figure 3: Open-hole well logs for 328-25R before installation of long string.



Cement Evaluation

The cement bond log amplitude shows isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 2). Late CBL signature arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was logged from 6498’ MD to 1400’ MD. Top of cement found at 1450’ MD.The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7” casing string during pre-operational testing.

Figure 4: Cement bond log example for 328-25R, after installation of long string casing. The Monterey Formation 26R top is at 5,220 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Planned Well Retrofitting

Prior to first injection, the existing wellbore will be reconfigured for monitoring through the following procedure:

1. Install and test Blowout Prevention Equipment (BOPE)
2. Pull existing injection tubing and packer
3. Clean out well to Plugback Measure Depth (PBMD) and remove Bridge plug
4. Plug back well below injection zone with class G Portland Cement
5. Acquire remaining pre-operational phase data per Att G and T&M docs
6. Install CCS injection tubing, packer, injection tree, and all monitoring equipment per T&M and well schematics.
7. Perform Standard Annular Pressure Test (SAPT) per T&M procedure
8. Suspend well temporarily for CCS project startup

Monitoring Well Plugging

CTV's Monitoring Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature profile, which could be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, during, and after injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 12' MD due to the depth reference to the kelly bushing 12' above ground level during drilling.

Table 6: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.276	6.366	6.366	6.276
Depth to bottom of tubing or drill pipe (ft)	6496	2390	1010	45

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Sacks of cement to be used (each plug)	258	25	25	5
Slurry volume to be pumped (ft^3)	52.84	5.12	5.12	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	5117	2265	885	20
Bottom of plug (ft)	6496	2390	1010	45
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.
2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.
3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.
5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.
6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.
7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.
8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):
    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.